Contents

Appendixes

Page

Tables

Figures

Figures (Continued) **Page**

1. Introduction

On August 14, 2003, large portions of the Midwest and Northeast United States and Ontario, Canada, experienced an electric power blackout. The outage affected an area with an estimated 50 million people and 61,800 megawatts (MW) of electric load in the states of Ohio, Michigan, Pennsylvania, New York, Vermont, Massachusetts, Connecticut, and New Jersey and the Canadian province of Ontario. The blackout began a few minutes after 4:00 pm Eastern Daylight Time (16:00 EDT), and power was not restored for 2 days in some parts of the United States. Parts of Ontario suffered rolling blackouts for more than a week before full power was restored.

On August 15, President George W. Bush and Prime Minister Jean Chrétien directed that a joint U.S.-Canada Power System Outage Task Force be established to investigate the causes of the blackout and how to reduce the possibility of future outages. They named U.S. Secretary of Energy Spencer Abraham and Herb Dhaliwal, Minister of Natural Resources, Canada, to chair the joint Task Force. Three other U.S. representatives and three other Canadian representatives were named to the Task Force. The U.S. members are Tom Ridge, Secretary of Homeland Security; Pat Wood, Chairman of the Federal Energy Regulatory Commission; and Nils Diaz, Chairman of the Nuclear Regulatory Commission. The Canadian members are Deputy Prime Minister John Manley, Deputy Prime Minister; Kenneth Vollman, Chairman of the National Energy Board; and Linda J. Keen, President and CEO of the Canadian Nuclear Safety Commission.

The Task Force divided its work into two phases:

- Phase I: Investigate the outage to determine its causes and why it was not contained.
- Phase II: Develop recommendations to reduce the possibility of future outages and minimize the scope of any that occur.

The Task Force created three Working Groups to assist in the Phase I investigation of the blackout—an Electric System Working Group (ESWG), a Nuclear Working Group (NWG), and a Security Working Group (SWG). They were tasked with overseeing and reviewing investigations of the conditions and events in their respective areas and determining whether they may have caused or affected the blackout. The Working Groups are made up of State and provincial representatives, Federal employees, and contractors working for the U.S. and Canadian government agencies represented on the Task Force.

This document provides an Interim Report, forwarded by the Working Groups, on the findings of the Phase I investigation. It presents the facts that the bi-national investigation has found regarding the causes of the blackout on August 14, 2003. The Working Groups and their analytic teams are confident of the accuracy of these facts and the analysis built upon them. This report does not offer speculations or assumptions not supported by evidence and analysis. Further, it does not attempt to draw broad conclusions or suggest policy recommendations; that task is to be undertaken in Phase II and is beyond the scope of the Phase I investigation.

This report will now be subject to public review and comment. The Working Groups will consider public commentary on the Interim Report and will oversee and review any additional analyses and investigation that may be required. This report will be finalized and made a part of the Task Force Final Report, which will also contain recommendations on how to minimize the likelihood and scope of future blackouts.

The Task Force will hold three public forums, or consultations, in which the public will have the opportunity to comment on this Interim Report and to present recommendations for consideration by the Working Groups and the Task Force.

The public may also submit comments and recommendations to the Task Force electronically or by mail. Electronic submissions may be sent to:

poweroutage@nrcan.gc.ca

and

blackout.report@hq.doe.gov.

Paper submissions may be sent by mail to:

Dr. Nawal Kamel
Special Adviser to the Deputy Minister
Natural Resources Canada
21st Floor
580 Booth Street
Ottawa, ON K1A 0E4

and

Mr. James W. Glotfelty
Director, Office of Electric Transmission and Distribution
U.S. Department of Energy
1000 Independence Avenue, S.W.
Washington, DC 20585

This Interim Report is divided into eight chapters, including this introductory chapter:

- Chapter 2 provides an overview of the institutional framework for maintaining and ensuring the reliability of the bulk power system in North America, with particular attention to the roles and responsibilities of several types of reliability-related organizations.
- Chapter 3 discusses conditions on the regional power system before August 14 and on August 14 before the events directly related to the blackout began.
- Chapter 4 addresses the causes of the blackout, with particular attention to the evolution of conditions on the afternoon of August 14, starting from normal operating conditions, then going into a period of abnormal but still potentially manageable conditions, and finally into an uncontrollable cascading blackout.
- Chapter 5 provides details on the cascade phase of the blackout.
- Chapter 6 compares the August 14, 2003, blackout with previous major North American power outages.
- Chapter 7 examines the performance of the nuclear power plants affected by the August 14 outage.
- Chapter 8 addresses issues related to physical and cyber security associated with the outage.

This report also includes four appendixes: a description of the investigative process that provided the basis for this report, a list of electricity acronyms, a glossary of electricity terms, and three transmittal letters pertinent to this report from the three Working Groups.

2. Overview of the North American Electric Power System and Its Reliability Organizations

The North American Power Grid Is One Large, Interconnected Machine

The North American electricity system is one of the great engineering achievements of the past 100 years. This electricity infrastructure represents more than $1 trillion in asset value, more than 200,000 miles (320,000 kilometers) of transmission lines operating at 230,000 volts and greater, 950,000 megawatts of generating capability, and nearly 3,500 utility organizations serving well over 100 million customers and 283 million people.

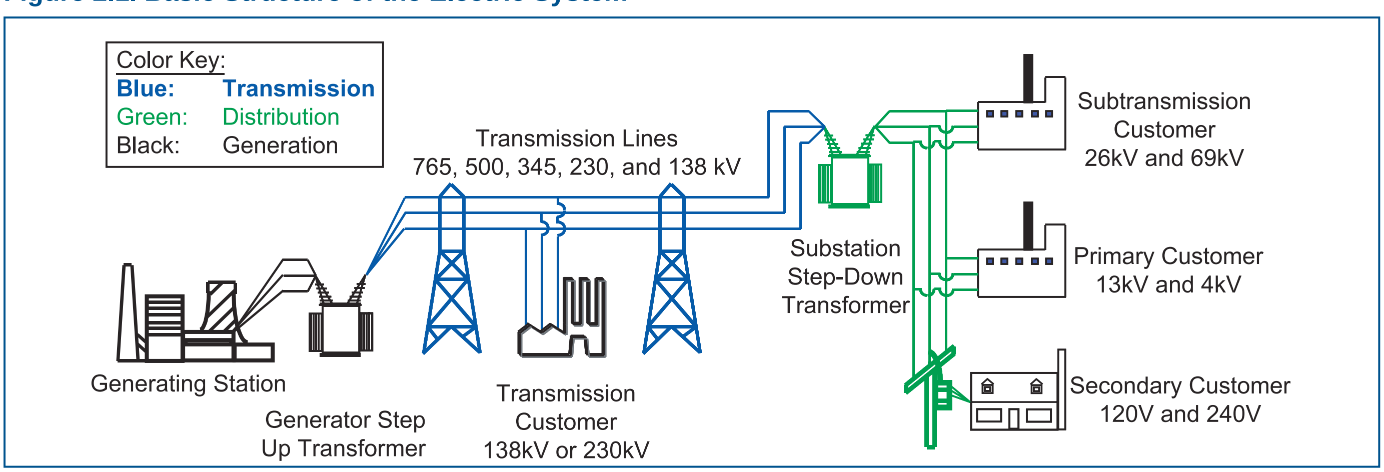
Modern society has come to depend on reliable electricity as an essential resource for national security; health and welfare; communications; finance; transportation; food and water supply; heating, cooling, and lighting; computers and electronics; commercial enterprise; and even entertainment and leisure—in short, nearly all aspects of modern life. Customers have grown to expect that electricity will almost always be available when needed at the flick of a switch. Most customers have also experienced local outages caused by a car hitting a power pole, a construction crew accidentally damaging a cable, or a lightning storm. What is not expected is the occurrence of a massive outage on a calm, warm day. Widespread electrical outages, such as the one that occurred on August 14, 2003, are rare, but they can happen if multiple reliability safeguards break down.

Providing reliable electricity is an enormously complex technical challenge, even on the most routine of days. It involves real-time assessment, control and coordination of electricity production at thousands of generators, moving electricity across an interconnected network of transmission lines, and ultimately delivering the electricity to millions of customers by means of a distribution network.

As shown in Figure 2.1, electricity is produced at lower voltages (10,000 to 25,000 volts) at generators from various fuel sources, such as nuclear, coal, oil, natural gas, hydro power, geothermal, photovoltaic, etc. Some generators are owned by the same electric utilities that serve the end-use customer; some are owned by independent power producers (IPPs); and others are owned by customers themselves—particularly large industrial customers.

Electricity from generators is "stepped up" to higher voltages for transportation in bulk over

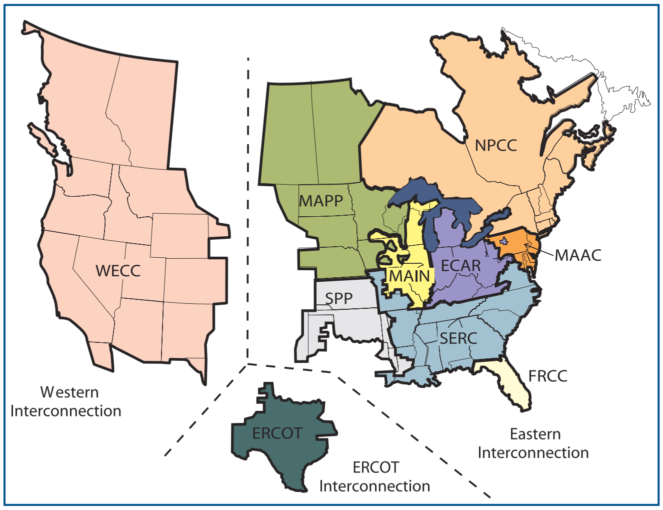
Figure 2.1. Basic Structure of the Electric System



transmission lines. Operating the transmission lines at high voltage (i.e., 230,000 to 765,000 volts) reduces the losses of electricity from conductor heating and allows power to be shipped economically over long distances. Transmission lines are interconnected at switching stations and substations to form a network of lines and stations called the power "grid." Electricity flows through the interconnected network of transmission lines from the generators to the loads in accordance with the laws of physics—along "paths of least resistance," in much the same way that water flows through a network of canals. When the power arrives near a load center, it is "stepped down" to lower voltages for distribution to customers. The bulk power system is predominantly an alternating current (AC) system, as opposed to a direct current (DC) system, because of the ease and low cost with which voltages in AC systems can be converted from one level to another. Some larger industrial and commercial customers take service at intermediate voltage levels (12,000 to 115,000 volts), but most residential customers take their electrical service at 120 and 240 volts.

While the power system in North America is commonly referred to as "the grid," there are actually three distinct power grids or "interconnections" (Figure 2.2). The Eastern Interconnection includes the eastern two-thirds of the continental United States and Canada from Saskatchewan east to the Maritime Provinces. The Western Interconnection includes the western third of the continental United States (excluding Alaska), the Canadian Provinces of Alberta and British Columbia, and a portion of Baja California Norte, Mexico. The third interconnection comprises most of the state of Texas. The three interconnections are electrically independent from each other except for a few small direct current (DC) ties that link them. Within each interconnection, electricity is produced the instant it is used, and flows over virtually all transmission lines from generators to loads.

Figure 2.2. NERC Interconnections



The northeastern portion of the Eastern Interconnection (about 10 percent of the interconnection's total load) was affected by the August 14 blackout. The other two interconnections were not affected.[1]

Planning and Reliable Operation of the Power Grid Are Technically Demanding

Reliable operation of the power grid is complex and demanding for two fundamental reasons:

- First, electricity flows at the speed of light (186,000 miles per second or 297,600 kilometers per second) and is not economically storable in large quantities. Therefore electricity must be produced the instant it is used.
- Second, the flow of alternating current (AC) electricity cannot be controlled like a liquid or gas by opening or closing a valve in a pipe, or switched like calls over a long-distance telephone network. Electricity flows freely along all available paths from the generators to the loads in accordance with the laws of physics—dividing among all connected flow paths in the network, in inverse proportion to the impedance (resistance plus reactance) on each path.

Maintaining reliability is a complex enterprise that requires trained and skilled operators, sophisticated computers and communications, and careful planning and design. The North American Electric Reliability Council (NERC) and its ten Regional Reliability Councils have developed system operating and planning standards for ensuring the reliability of a transmission grid that are based on seven key concepts:

- Balance power generation and demand continuously.
- Balance reactive power supply and demand to maintain scheduled voltages.
- Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.

- Keep the system in a stable condition.
- Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N-1 criterion").
- Plan, design, and maintain the system to operate reliably.
- Prepare for emergencies.

These seven concepts are explained in more detail below.

1. **Balance power generation and demand continuously.** To enable customers to use as much electricity as they wish at any moment, production by the generators must be scheduled or "dispatched" to meet constantly changing demands, typically on an hourly basis, and then fine-tuned throughout the hour, sometimes through the use of automatic generation controls to continuously match generation to actual demand. Demand is somewhat predictable, appearing as a daily demand curve—in the summer, highest during the afternoon and evening and lowest in the middle of the night, and higher on weekdays when most businesses are open (Figure 2.3).

   Failure to match generation to demand causes the frequency of an AC power system (nominally 60 cycles per second or 60 Hertz) to increase (when generation exceeds demand) or decrease (when generation is less than demand) (Figure 2.4). Random, small variations in frequency are normal, as loads come on and off and generators modify their output to follow the demand changes. However, large deviations in frequency can cause the rotational speed of generators to fluctuate, leading to vibrations that can damage generator turbine blades and other equipment. Extreme low frequencies can trigger automatic under-frequency "load shedding," which takes blocks of customers off-line in order to prevent a total collapse of the electric system. As will be seen later in this report, such an imbalance of generation and demand can also occur when the system responds to major disturbances by breaking into separate "islands"; any such island may have an excess or a shortage of generation, compared to demand within the island.

2. **Balance reactive power supply and demand to maintain scheduled voltages.** Reactive power sources, such as capacitor banks and generators, must be adjusted during the day to maintain voltages within a secure range pertaining to all system electrical equipment (stations, transmission lines, and customer equipment). Most generators have automatic voltage regulators that cause the reactive power output of generators to increase or decrease to control voltages to scheduled levels. Low voltage can cause electric system instability or collapse and, at distribution voltages, can cause damage to motors and the failure of electronic equipment. High voltages can exceed the insulation capabilities of equipment and cause dangerous electric arcs ("flashovers").

3. **Monitor flows over transmission lines and other facilities to ensure that thermal (heating) limits are not exceeded.** The dynamic interactions between generators and loads, combined with the fact that electricity flows freely across all interconnected circuits, mean that power flow is ever-changing on transmission and distribution lines. All lines, transformers, and other equipment carrying electricity are heated by the flow of electricity through them. The

Figure 2.3. PJM Load Curve, August 18-24, 2003

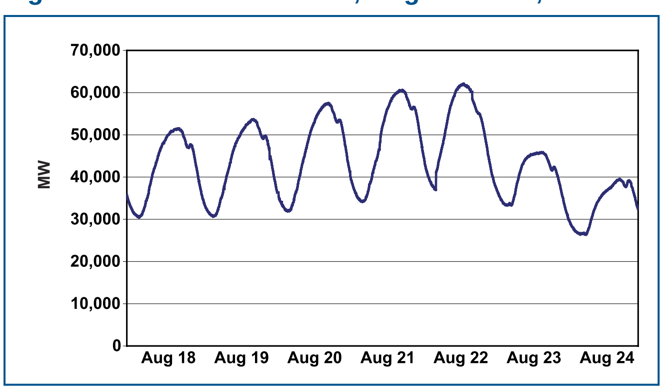
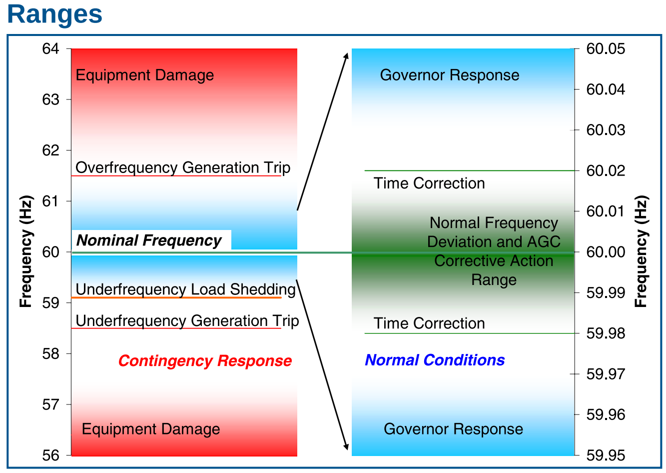


Figure 2.4. Normal and Abnormal Frequency Ranges



Local Supplies of Reactive Power Are Essential to Maintaining Voltage Stability

A generator typically produces some mixture of "active" and "reactive" power, and the balance between them can be adjusted at short notice to meet changing conditions. Active power, measured in watts, is the form of electricity that powers equipment. Reactive power, a characteristic of AC systems, is measured in volt-amperes reactive (VAr), and is the energy supplied to create or be stored in electric or magnetic fields in and around electrical equipment. Reactive power is particularly important for equipment that relies on magnetic fields for the production of induced electric currents (e.g., motors, transformers, pumps, and air conditioning.) Transmission lines both consume and produce reactive power. At light loads they are net producers, and at heavy loads, they are heavy consumers. Reactive power consumption by these facilities or devices tends to depress transmission voltage, while its production (by generators) or injection (from storage devices such as capacitors) tends to support voltage. Reactive power can be transmitted only over relatively short distances, and thus must be supplied as needed from nearby generators or capacitor banks. If reactive power cannot be supplied promptly and in sufficient quantity, voltages decay, and in extreme cases a "voltage collapse" may result.

flow must be limited to avoid overheating and damaging the equipment. In the case of overhead power lines, heating also causes the metal conductor to stretch or expand and sag closer to ground level. Conductor heating is also affected by ambient temperature, wind, and other factors. Flow on overhead lines must be limited to ensure that the line does not sag into obstructions below such as trees or telephone lines, or violate the minimum safety clearances between the energized lines and other objects. (A short circuit or "flashover"—which can start fires or damage equipment—can occur if an energized line gets too close to another object). All electric lines, transformers and other current-carrying devices are monitored continuously to ensure that they do not become overloaded or violate other operating constraints. Multiple ratings are typically used, one for normal conditions and a higher rating for emergencies. The primary means of limiting the flow of power on transmission lines is to adjust selectively the output of generators.

4. **Keep the system in a stable condition.** Because the electric system is interconnected and dynamic, electrical stability limits must be observed. Stability problems can develop very quickly—in just a few cycles (a cycle is 1/60th of a second)—or more slowly, over seconds or minutes. The main concern is to ensure that generation dispatch and the resulting power flows and voltages are such that the system is stable at all times. (As will be described later in this report, part of the Eastern Interconnection became unstable on August 14, resulting in a cascading outage over a wide area.) Stability limits, like thermal limits, are expressed as a maximum amount of electricity that can be safely transferred over transmission lines.

   There are two types of stability limits: (1) Voltage stability limits are set to ensure that the unplanned loss of a line or generator (which may have been providing locally critical reactive power support, as described previously) will not cause voltages to fall to dangerously low levels. If voltage falls too low, it begins to collapse uncontrollably, at which point automatic relays either shed load or trip generators to avoid damage. (2) Power (angle) stability limits are set to ensure that a short circuit or an unplanned loss of a line, transformer, or generator will not cause the remaining generators and loads being served to lose synchronism with one another. (Recall that all generators and loads within an interconnection must operate at or very near a common 60 Hz frequency.) Loss of synchronism with the common frequency means generators are operating out-of-step with one another. Even modest losses of synchronism can result in damage to generation equipment. Under extreme losses of synchronism, the grid may break apart into separate electrical islands; each island would begin to maintain its own frequency, determined by the load/generation balance within the island.

5. **Operate the system so that it remains in a reliable condition even if a contingency occurs, such as the loss of a key generator or transmission facility (the "N minus 1 criterion").** The central organizing principle of electricity reliability management is to plan for the unexpected. The unique features of electricity mean

that problems, when they arise, can spread and escalate very quickly if proper safeguards are not in place. Accordingly, through years of experience, the industry has developed a sequence of defensive strategies for maintaining reliability based on the assumption that equipment can and will fail unexpectedly upon occasion.

This principle is expressed by the requirement that the system must be operated at all times to ensure that it will remain in a secure condition (generally within emergency ratings for current and voltage and within established stability limits) following the loss of the most important generator or transmission facility (a "worst single contingency"). This is called the "N-1 criterion." In other words, because a generator or line trip can occur at any time from random failure, the power system must be operated in a preventive mode so that the loss of the most important generator or transmission facility does not jeopardize the remaining facilities in the system by causing them to exceed their emergency ratings or stability limits, which could lead to a cascading outage.

Further, when a contingency does occur, the operators are required to identify and assess immediately the new worst contingencies, given the changed conditions, and promptly make any adjustments needed to ensure that if one of them were to occur, the system would still remain operational and safe. NERC operating policy requires that the system be restored as soon as practical but within no more than 30 minutes to compliance with normal limits, and to a condition where it can once again withstand the next-worst single contingency without violating thermal, voltage, or stability limits. A few areas of the grid are operated to withstand the concurrent loss of two or more facilities (i.e., "N-2"). This may be done, for example, as an added safety measure to protect a densely populated metropolitan area or when lines share a common structure and could be affected by a common failure mode, e.g., a single lightning strike.

6. **Plan, design, and maintain the system to operate reliably.** Reliable power system operation requires far more than monitoring and controlling the system in real-time. Thorough planning, design, maintenance, and analysis are required to ensure that the system can be operated reliably and within safe limits. Short-term planning addresses day-ahead and week-ahead operations planning; long-term planning focuses on providing adequate generation resources and transmission capacity to ensure that in the future the system will be able to withstand severe contingencies without experiencing widespread, uncontrolled cascading outages.

   A utility that serves retail customers must estimate future loads and, in some cases, arrange for adequate sources of supplies and plan adequate transmission and distribution infrastructure. NERC planning standards identify a range of possible contingencies and set corresponding expectations for system performance under several categories of possible events. Three categories represent the more probable types of events that the system must be planned to withstand. A fourth category represents "extreme events" that may involve substantial loss of customer load and generation in a widespread area. NERC planning standards also address requirements for voltage support and reactive power, disturbance monitoring, facility ratings, system modeling and data requirements, system protection and control, and system restoration.

7. **Prepare for emergencies.** System operators are required to take the steps described above to plan and operate a reliable power system, but emergencies can still occur because of external factors such as severe weather, operator error, or equipment failures that exceed planning, design, or operating criteria. For these rare events, the operating entity is required to have emergency procedures covering a credible range of emergency scenarios. Operators must be trained to recognize and take effective action in response to these emergencies. To deal with a system emergency that results in a blackout, such as the one that occurred on August 14, 2003, there must be procedures and capabilities to use "black start" generators (capable of restarting with no external power source) and to coordinate operations in order to restore the system as quickly as possible to a normal and reliable condition.

Reliability Organizations Oversee Grid Reliability in North America

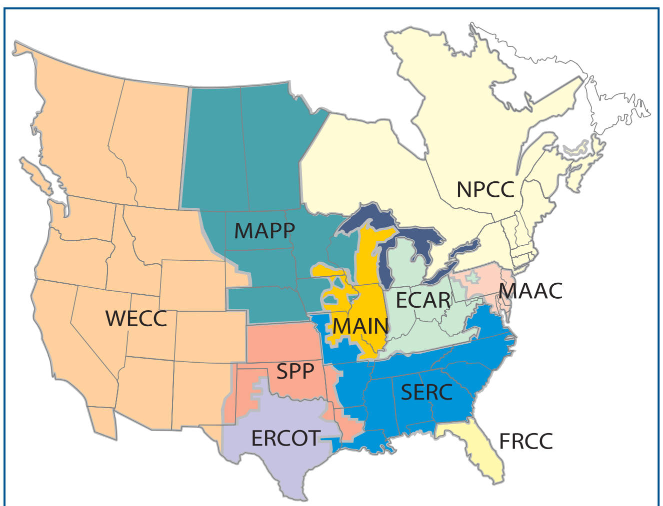
NERC is a non-governmental entity whose mission is to ensure that the bulk electric system in North America is reliable, adequate and secure.

The organization was established in 1968, as a result of the Northeast blackout in 1965. Since its inception, NERC has operated as a voluntary organization, relying on reciprocity, peer pressure and the mutual self-interest of all those involved to ensure compliance with reliability requirements. An independent board governs NERC.

To fulfill its mission, NERC:

- Sets standards for the reliable operation and planning of the bulk electric system.
- Monitors and assesses compliance with standards for bulk electric system reliability.
- Provides education and training resources to promote bulk electric system reliability.
- Assesses, analyzes and reports on bulk electric system adequacy and performance.
- Coordinates with Regional Reliability Councils and other organizations.
- Coordinates the provision of applications (tools), data and services necessary to support the reliable operation and planning of the bulk electric system.
- Certifies reliability service organizations and personnel.
- Coordinates critical infrastructure protection of the bulk electric system.
- Enables the reliable operation of the interconnected bulk electric system by facilitating information exchange and coordination among reliability service organizations.

Figure 2.5. NERC Regions



Recent changes in the electricity industry have altered many of the traditional mechanisms, incentives and responsibilities of the entities involved in ensuring reliability, to the point that the voluntary system of compliance with reliability standards is generally recognized as not adequate to current needs.[2] NERC and many other electricity organizations support the development of a new mandatory system of reliability standards and compliance, backstopped in the United States by the Federal Energy Regulatory Commission. This will require federal legislation in the United States to provide for the creation of a new electric reliability organization with the statutory authority to enforce compliance with reliability standards among all market participants. Appropriate government entities in Canada and Mexico are prepared to take similar action, and some have already done so. In the meantime, NERC encourages compliance with its reliability standards through an agreement with its members.

NERC's members are ten Regional Reliability Councils. (See Figure 2.5 for a map showing the locations and boundaries of the regional councils.) The regional councils and NERC have opened their membership to include all segments of the electric industry: investor-owned utilities; federal power agencies; rural electric cooperatives; state, municipal and provincial utilities; independent power producers; power marketers; and end-use customers. Collectively, the members of the NERC regions account for virtually all the electricity supplied in the United States, Canada, and a portion of Baja California Norte, Mexico. The ten regional councils jointly fund NERC and adapt NERC standards to meet the needs of their regions. The August 14 blackout affected three NERC regional reliability councils—East Central Area Reliability Coordination Agreement (ECAR), Mid-Atlantic Area Council (MAAC), and Northeast Power Coordinating Council (NPCC).

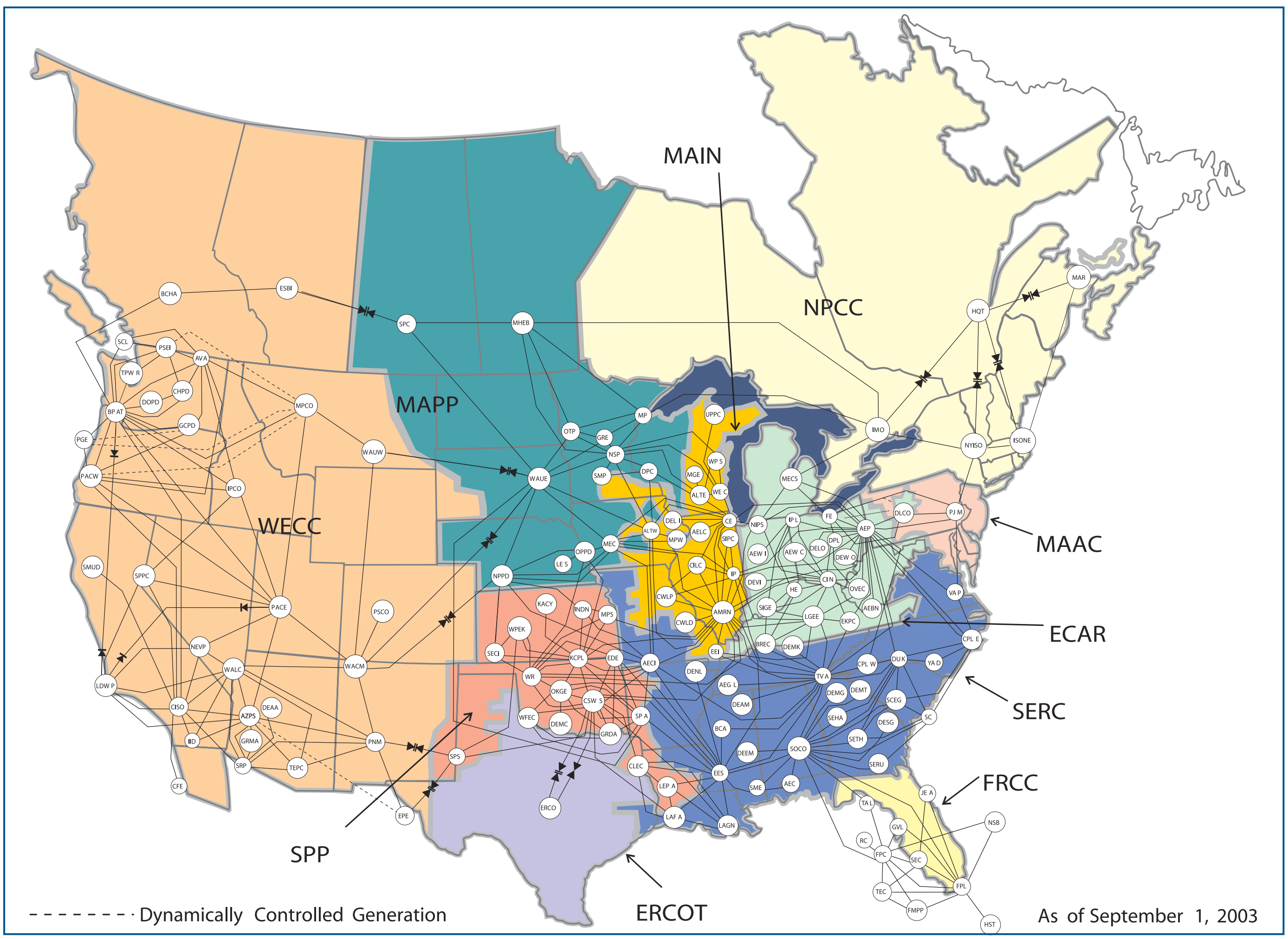
"Control areas" are the primary operational entities that are subject to NERC and regional council standards for reliability. A control area is a geographic area within which a single entity, Independent System Operator (ISO), or Regional Transmission Organization (RTO) balances generation and loads in real time to maintain reliable operation. Control areas are linked with each other through transmission interconnection tie lines. Control area operators control generation directly to maintain their electricity interchange schedules with other control areas. They also operate collectively to support the reliability of their interconnection. As shown in Figure 2.6, there are approximately 140 control areas in North America. The control area dispatch centers have sophisticated monitoring and control systems and are staffed 24 hours per day, 365 days per year.

Traditionally, control areas were defined by utility service area boundaries and operations were largely managed by vertically integrated utilities that owned and operated generation, transmission, and distribution. While that is still true in some areas, there has been significant restructuring of operating functions and some consolidation of control areas into regional operating entities. Utility industry restructuring has led to an unbundling of generation, transmission and distribution activities such that the ownership and operation of these assets have been separated either functionally or through the formation of independent entities called Independent System Operators (ISOs) and Regional Transmission Organizations (RTOs).

- ISOs and RTOs in the United States have been authorized by FERC to implement aspects of the Energy Policy Act of 1992 and subsequent FERC policy directives.
- The primary functions of ISOs and RTOs are to manage in real time and on a day-ahead basis the reliability of the bulk power system and the operation of wholesale electricity markets within their footprint.
- ISOs and RTOs do not own transmission assets; they operate or direct the operation of assets owned by their members.
- ISOs and RTOs may be control areas themselves, or they may encompass more than one control area.
- ISOs and RTOs may also be NERC Reliability Coordinators, as described below.

Five RTOs/ISOs are within the area directly affected by the August 14 blackout. They are:

Figure 2.6. NERC Regions and Control Areas



- Midwest Independent System Operator (MISO)
- PJM Interconnection (PJM)
- New York Independent System Operator (NYISO)
- New England Independent System Operator (ISO-NE)
- Ontario Independent Market Operator (IMO)

Reliability coordinators provide reliability oversight over a wide region. They prepare reliability assessments, provide a wide-area view of reliability, and coordinate emergency operations in real time for one or more control areas. They do not participate in the wholesale or retail market functions. There are currently 18 reliability coordinators in North America. Figure 2.7 shows the locations and boundaries of their respective areas.

Key Parties in the Pre-Cascade Phase of the August 14 Blackout

The initiating events of the blackout involved two control areas—FirstEnergy (FE) and American Electric Power (AEP)—and their respective reliability coordinators, MISO and PJM (see Figures 2.7 and 2.8). These organizations and their reliability responsibilities are described briefly in this final subsection.

1. **FirstEnergy operates a control area in northern Ohio.** FirstEnergy (FE) consists of seven electric utility operating companies. Four of these companies, Ohio Edison, Toledo Edison, The Illuminating Company, and Penn Power, operate in the NERC ECAR region, with MISO serving as their reliability coordinator. These four companies now operate as one integrated control area managed by FE.[3]

2. **American Electric Power (AEP) operates a control area in Ohio just south of FE.** AEP is both a transmission operator and a control area operator.

3. **Midwest Independent System Operator (MISO) is the reliability coordinator for FirstEnergy.** The Midwest Independent System Operator (MISO) is the reliability coordinator for a region of more than one million square miles, stretching from Manitoba, Canada in the north to Kentucky in the south, from Montana in the west to western Pennsylvania in the east. Reliability coordination is provided by two offices, one in Minnesota, and the other at the MISO headquarters in Indiana. Overall, MISO provides reliability coordination for 37 control areas, most of which are members of MISO.

4. **PJM is AEP's reliability coordinator.** PJM is one of the original ISOs formed after FERC orders 888 and 889, but was established as a regional power pool in 1935. PJM recently expanded its footprint to include control areas and transmission operators within MAIN and ECAR (PJM-West). It performs its duties as a reliability coordinator in different ways, depending on the control areas involved. For PJM-East, it is both the control area and reliability coordinator for ten utilities, whose transmission systems span the Mid-Atlantic region of New Jersey, most of Pennsylvania, Delaware, Maryland, West Virginia, Ohio, Virginia, and the District of Columbia. The PJM-West facility has the reliability coordinator desk for five control areas (AEP, Commonwealth Edison, Duquesne Light,

Figure 2.7. NERC Reliability Coordinators

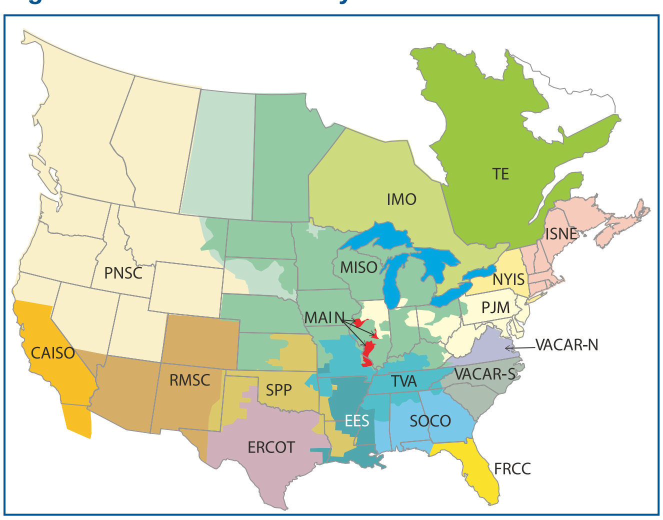
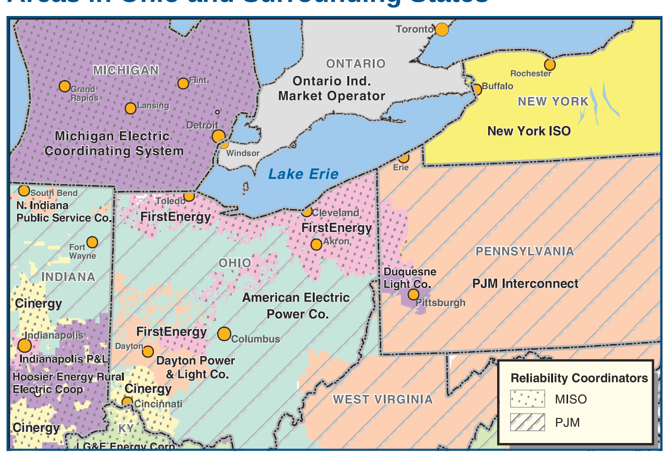


Figure 2.8. Reliability Coordinators and Control Areas in Ohio and Surrounding States



Dayton Power and Light, and Ohio Valley Electric Cooperative) and three generation-only control areas (Duke Energy's Washington County (Ohio) facility, Duke's Lawrence County/Hanging Rock (Ohio) facility, and Allegheny Energy's Buchanan (West Virginia) facility.

Reliability Responsibilities of Control Area Operators and Reliability Coordinators

1. **Control area operators have primary responsibility for reliability.** Their most important responsibilities, in the context of this report, are:

N-1 criterion. NERC Operating Policy 2.A—Transmission Operations:

"All CONTROL AREAS shall operate so that instability, uncontrolled separation, or cascading outages will not occur as a result of the most severe single contingency."

Emergency preparedness and emergency response. NERC Operating Policy 5—Emergency Operations, General Criteria:

"Each system and CONTROL AREA shall promptly take appropriate action to relieve any abnormal conditions, which jeopardize reliable Interconnection operation."

"Each system, CONTROL AREA, and Region shall establish a program of manual and automatic load shedding which is designed to arrest frequency or voltage decays that could result in an uncontrolled failure of components of the interconnection."

Institutional Complexities and Reliability in the Midwest

The institutional arrangements for reliability in the Midwest are much more complex than they are in the Northeast-the areas covered by the Northeast Power Coordinating Council (NPCC) and the Mid-Atlantic Area Council (MAAC). There are two principal reasons for this complexity. One is that in NPCC and MAAC, the independent system operator (ISO) also serves as the single control area operator for the individual member systems. In comparison, MISO provides reliability coordination for 35 control areas in the ECAR, MAIN, and MAPP regions and 2 others in the SPP region, and PJM provides reliability coordination for 8 control areas in the ECAR and MAIN regions (plus one in MAAC). (See table below.) This results in 18 control-area-to-control-area interfaces across the PJM/MISO reliability coordinator boundary.

The other is that MISO has less reliability-related authority over its control area members than PJM has over its members. Arguably, this lack of authority makes day-to-day reliability operations more challenging. Note, however, that (1) FERC's authority to require that MISO have greater authority over its members is limited; and (2) before approving MISO, FERC asked NERC for a formal assessment of whether reliability could be maintained under the arrangements proposed by MISO and PJM. After reviewing proposed plans for reliability coordination within and between PJM and MISO, NERC replied affirmatively but provisionally. NERC conducted audits in November and December 2002 of the MISO and PJM reliability plans, and some of the recommendations of the audit teams are still being addressed. The adequacy of the plans and whether the plans were being implemented as written are factors in the NERC's ongoing investigation.

Reliability Coordinator (RC)	Control Areas in RC Area	Regional Reliability Councils Affected and Number of Control Areas	Control Areas of Interest in RC Area
MISO	37	ECAR (12), MAIN (9), MAPP (14), SPP (2)	FE, Cinergy, Michigan Electric Coordinated System
PJM	9	MAAC (1), ECAR (7), MAIN (1)	PJM, AEP, Dayton Power & Light
ISO New England	2	NPCC (2)	ISONE, Maritimes
New York ISO	1	NPCC (1)	NYISO
Ontario Independent Market Operator	1	NPCC (1)	IMO
Trans-Energie	1	NPCC (1)	Hydro Québec

NERC Operating Policy 5.A—Coordination with Other Systems:

> "A system, CONTROL AREA, or pool that is experiencing or anticipating an operating emergency shall communicate its current and future status to neighboring systems, CONTROL AREAS, or pools and throughout the interconnection.... A system shall inform other systems ... whenever ... the system's condition is burdening other systems or reducing the reliability of the Interconnection .... [or whenever] the system's line loadings and voltage/reactive levels are such that a single contingency could threaten the reliability of the Interconnection."

NERC Operating Policy 5.C—Transmission System Relief:

> "Action to correct an OPERATING SECURITY LIMIT violation shall not impose unacceptable stress on internal generation or transmission equipment, reduce system reliability beyond acceptable limits, or unduly impose voltage or reactive burdens on neighboring systems. If all other means fail, corrective action may require load reduction."

Operating personnel and training: NERC Operating Policy 8.B—Training:

> "Each OPERATING AUTHORITY should periodically practice simulated emergencies. The scenarios included in practice situations should represent a variety of operating conditions and emergencies."

What Constitutes an Operating Emergency?

An operating emergency is an unsustainable condition that cannot be resolved using the resources normally available. The NERC Operating Manual defines a "capacity emergency" as when a system's or pool's operating generation capacity, plus firm purchases from other systems, to the extent available or limited by transfer capability, is inadequate to meet its demand plus its regulating requirements. It defines an "energy emergency" as when a load-serving entity has exhausted all other options and can no longer provide its customers' expected energy requirements. A transmission emergency exists when "the system's line loadings and voltage/ reactive levels are such that a single contingency could threaten the reliability of the Interconnection." Control room operators and dispatchers are given substantial latitude to determine when to declare an emergency. (See page 42 in Chapter 4 for more detail.)

2. **Reliability Coordinators** such as MISO and PJM are expected to comply with all aspects of NERC Operating Policies, especially Policy 9, Reliability Coordinator Procedures, and its appendices. Key requirements include:

   NERC Operating Policy 9, Criteria for Reliability Coordinators, 5.2:

   > Have "detailed monitoring capability of the RELIABILITY AREA and sufficient monitoring capability of the surrounding RELIABILITY AREAS to ensure potential security violations are identified."

   NERC Operating Policy 9, Functions of Reliability Coordinators, 1.7:

   > "Monitor the parameters that may have significant impacts within the RELIABILITY AREA and with neighboring RELIABILITY AREAS with respect to ... sharing with other RELIABILITY COORDINATORS any information regarding potential, expected, or actual critical operating conditions that could negatively impact other RELIABILITY AREAS. The RELIABILITY COORDINATOR will coordinate with other RELIABILITY COORDINATORS and CONTROL AREAS as needed to develop appropriate plans to mitigate negative impacts of potential, expected, or actual critical operating conditions...."

   NERC Operating Policy 9, Functions of Reliability Coordinators, 6:

   > "Conduct security assessment and monitoring programs to assess contingency situations. Assessments shall be made in real time and for the operations planning horizon at the CONTROL AREA level with any identified problems reported to the RELIABILITY COORDINATOR. The RELIABILITY COORDINATOR is to ensure that CONTROL AREA, RELIABILITY AREA, and regional boundaries are sufficiently modeled to capture any problems crossing such boundaries."

Endnotes

[1] The province of Quebec, although considered a part of the Eastern Interconnection, is connected to the rest of the Eastern Interconnection primarily by DC ties. In this instance, the DC ties acted as buffers between portions of the Eastern Interconnection; transient disturbances propagate through them less readily. Therefore, the electricity system in Quebec was not affected by the outage, except for a small portion of the

province's load that is directly connected to Ontario by AC transmission lines. (Although DC ties can act as a buffer between systems, the tradeoff is that they do not allow instantaneous generation support following the unanticipated loss of a generating unit.)

[2] See, for example, *Maintaining Reliability in a Competitive Electric Industry* (1998), a report to the U.S. Secretary of Energy by the Task Force on Electric Systems Reliability; *National Energy Policy* (2001), a report to the President of the United States by the National Energy Policy Development Group, p. 7-6; and *National Transmission Grid Study* (2002), U.S. Dept. of Energy, pp. 46-48.

[3] The remaining three FE companies, Penelec, Met-Ed, and Jersey Central Power & Light, are in the NERC MAAC region and have PJM as their reliability coordinator. The focus of this report is on the portion of FE in ECAR reliability region and within the MISO reliability coordinator footprint.

3. Status of the Northeastern Power Grid Before the Blackout Sequence Began

Summary

This chapter reviews the state of the northeast portion of the Eastern Interconnection during the days prior to August 14, 2003 and up to 15:05 EDT on August 14 to determine whether conditions at that time were in some way unusual and might have contributed to the initiation of the blackout. The Task Force's investigators found that at 15:05 EDT, immediately before the tripping (automatic shutdown) of FirstEnergy's (FE) Harding-Chamberlin 345-kV transmission line, the system was able to be operated reliably following the occurrence of any of more than 800 contingencies, including the loss of the Harding-Chamberlin line. At that point the system was being operated near (but still within) prescribed limits and in compliance with NERC's operating policies.

Determining that the system was in a reliable operational state at that time is extremely significant for understanding the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a direct cause of the blackout. This eliminates a number of possible causes of the blackout, whether individually or in combination with one another, such as:

- High power flows to Canada
- System frequency variations
- Low voltages earlier in the day or on prior days
- Low reactive power output from IPPs
- Unavailability of individual generators or transmission lines.

It is important to emphasize that establishing whether conditions were normal or unusual prior to and on August 14 has no direct bearing on the responsibilities and actions expected of the organizations and operators who are charged with ensuring power system reliability. As described in Chapter 2, the electricity industry has developed and codified a set of mutually reinforcing reliability standards and practices to ensure that system operators are prepared for the unexpected. The basic assumption underlying these standards and practices is that power system elements will fail or become unavailable in unpredictable ways. Sound reliability management is designed to ensure that safe operation of the system will continue following the unexpected loss of any key element (such as a major generator or key transmission facility). These practices have been designed to maintain a functional and reliable grid, regardless of whether actual operating conditions are normal. It is a basic principle of reliability management that "operators must operate the system they have in front of them"—unconditionally.

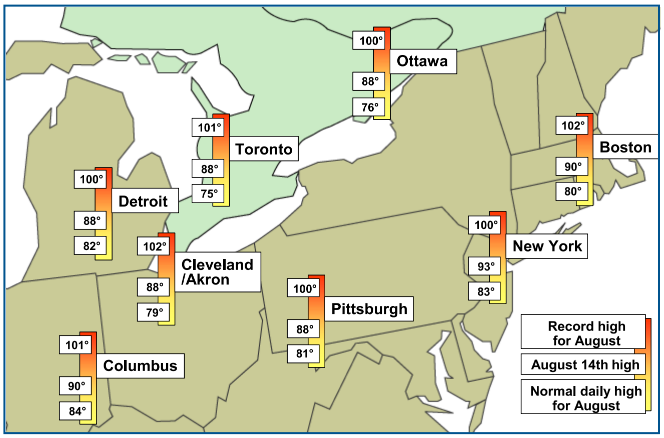
In terms of day-ahead planning, this means evaluating and if necessary adjusting the planned generation pattern (scheduled electricity transactions) to change the transmission flows, so that if a key facility were lost, the operators would still be able to readjust the remaining system and operate within safe limits. In terms of real-time operations, this means that the system should be operated at all times so as to be able to withstand the loss of any single facility and still remain within the system's thermal, voltage, and stability limits. If a facility is lost unexpectedly, the system operators must determine whether to make operational changes to ensure that the remaining system is able to withstand the loss of yet another key element and still remain able to operate within safe limits. This includes adjusting generator outputs, curtailing electricity transactions, and if necessary, shedding interruptible and firm customer load—i.e., cutting some customers off temporarily, and in the right locations, to reduce electricity demand to a level that matches what the system is then able to deliver safely.

Electric Demands on August 14

Temperatures on August 14 were above normal throughout the northeast region of the United

States and in eastern Canada. As a result, electricity demands were high due to high air conditioning loads typical of warm days in August, though not unusually so. System operators had successfully managed higher demands both earlier in the summer and in previous years. Recorded peak electric demands throughout the region on August 14 were below peak demands recorded earlier in the summer of 2003 (Figure 3.1).

Figure 3.1. August 2003 Temperatures in the U.S. Northeast and Eastern Canada



Power Flow Patterns

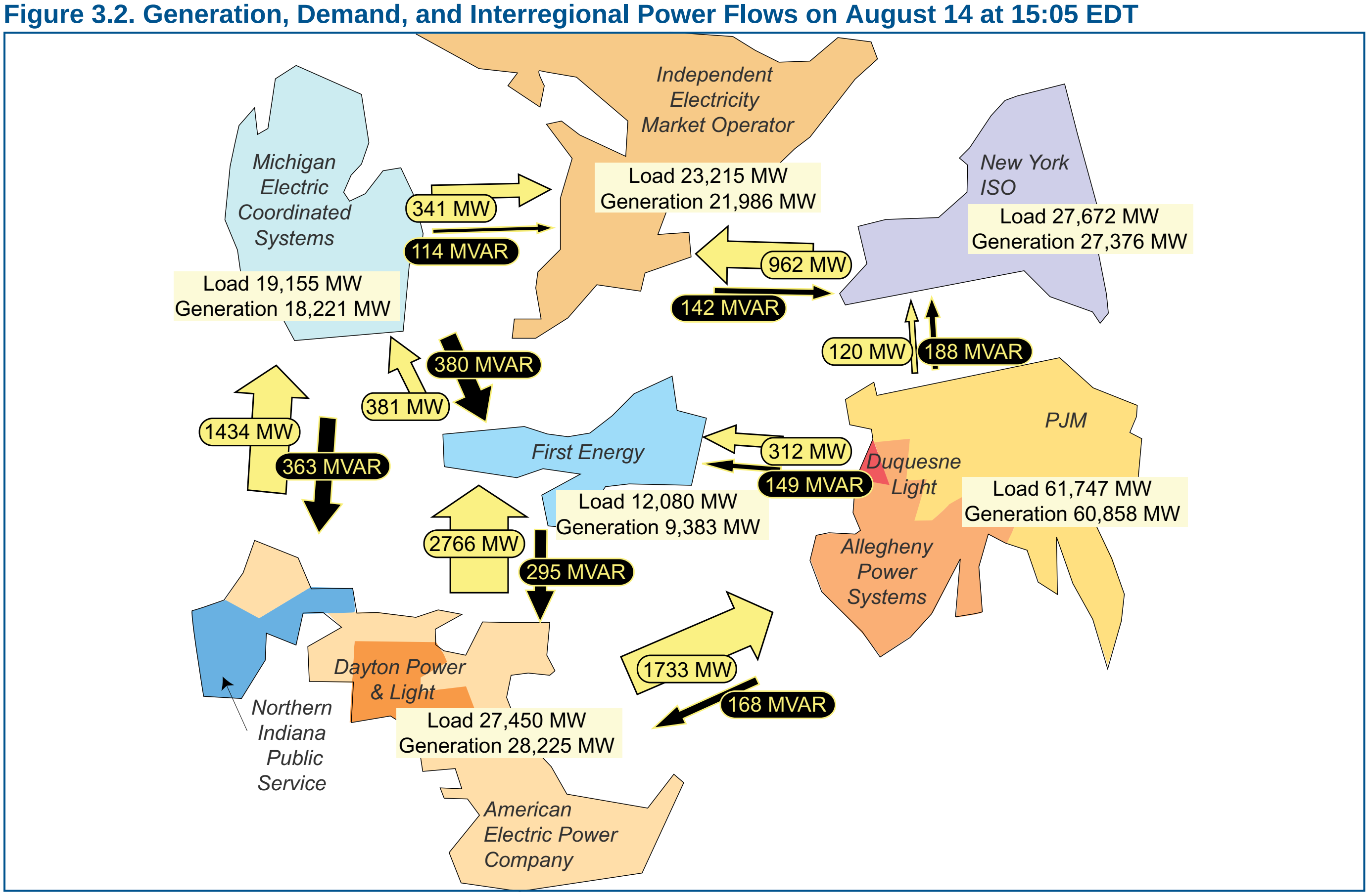
On August 14, the flow of power through the ECAR region was heavy as a result of large transfers of power from the south (Tennessee, Kentucky, Missouri, etc.) and west (Wisconsin, Minnesota, Illinois, etc.) to the north (Ohio, Michigan, and Ontario) and east (New York). The destinations for much of the power were northern Ohio, Michigan, PJM, and Ontario (Figure 3.2).

While heavy, these transfers were not beyond previous levels or in directions not seen before (Figure 3.3). The level of imports into Ontario on August 14 was high but not unusual, and well within IMO's import capability. Ontario's IMO is a frequent importer of power, depending on the availability and price of generation within Ontario. IMO had imported similar and higher amounts of power several times during the summers of 2002 and 2003.

System Frequency

Although system frequency on the Eastern Interconnection was somewhat more variable on

Figure 3.2. Generation, Demand, and Interregional Power Flows on August 14 at 15:05 EDT



August 14 prior to 15:05 EDT compared with recent history, it was well within the bounds of safe operating practices as outlined in NERC operating policies. As a result, system frequency variation was not a cause of the initiation of the blackout. But once the cascade was initiated, the large frequency swings that were induced became a principal means by which the blackout spread across a wide area (Figure 3.4).

Frequency Management

Each control area is responsible for maintaining a balance between its generation and demand. If persistent under-frequency occurs, at least one control area somewhere is "leaning on the grid," meaning that it is taking unscheduled electricity from the grid, which both depresses system frequency and creates unscheduled power flows. In practice, minor deviations at the control area level are routine; it is very difficult to maintain an exact balance between generation and demand. Accordingly, NERC has established operating rules that specify maximum permissible deviations, and focus on prohibiting persistent deviations, but not instantaneous ones. NERC monitors the performance of control areas through specific measures of control performance that gauge how accurately each control area matches its load and generation.

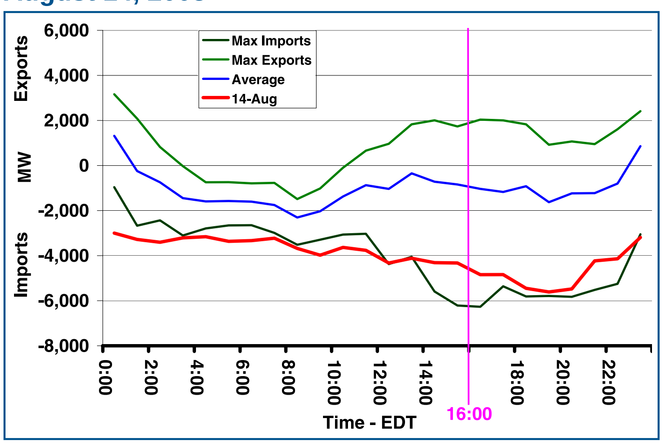
Assuming stable conditions, the system frequency is the same across an interconnected grid at any particular moment. System frequency will vary from moment to moment, however, depending on the second-to-second balance between aggregate generation and aggregate demand across the interconnection. System frequency is monitored on a continuous basis.

Generation Facilities Unavailable on August 14

Several key generators in the region were out of service going into the day of August 14. On any given day, some generation and transmission capacity is unavailable; some facilities are out for routine maintenance, and others have been forced out by an unanticipated breakdown and require repairs. August 14, 2003, was no exception (Table 3.1).

The generating units that were not available on August 14 provide real and reactive power directly to the Cleveland, Toledo, and Detroit areas. Under standard practice, system operators take into account the unavailability of such units and any

Figure 3.3. Northeast Central Area Scheduled Imports and Exports: Summer 2003 Compared to August 14, 2003



Note: Area covered includes ECAR, PJM, Ontario, and New York, without imports from the Maritime Provinces, ISO-New England, or Hydro-Quebec.

Figure 3.4. Frequency on August 14, 2003, up to 15:31 EDT

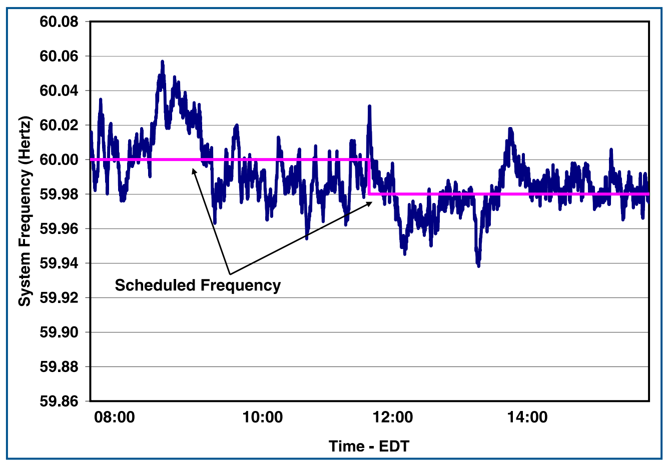


Table 3.1. Generators Not Available on August 14

Generator	Rating	Reason
Davis-Besse Nuclear Unit	750 MW	Prolonged NRC-ordered outage beginning on 3/22/02
Eastlake Unit 4	238 MW	Forced outage on 8/13/03
Monroe Unit 1	817 MW	Planned outage, taken out of service on 8/8/03
Cook Nuclear Unit 2	1,060 MW	Outage began on 8/13/03

transmission facilities known to be out of service in the day-ahead planning studies they perform to determine the condition of the system for the next day. Knowing the status of key facilities also helps operators determine in advance the safe electricity transfer levels for the coming day.

MISO's day-ahead planning studies for August 14 took these generator outages and known transmission outages into account and determined that the regional system could still be operated safely. The unavailability of these generation units and transmission facilities did not cause the blackout.

Voltages

During the days before August 14 and throughout the morning and mid-day on August 14, voltages were depressed in a variety of locations in northern Ohio because of high air conditioning demand and other loads, and power transfers into and across the region. (Unlike frequency, which is constant across the interconnection, voltage varies by location, and operators monitor voltages continuously at key locations across their systems.) However, actual measured voltage levels at key points on FE's transmission system on the morning of August 14 and up to 15:05 EDT were within the range previously specified by FE as acceptable. Note, however, that many control areas in the Eastern Interconnection have set their acceptable voltage bands at levels higher than that used by FE. For example, AEP's minimum acceptable voltage level is 95% of a line's nominal rating, as compared to FE's 92%.[1]

Voltage management is especially challenging on hot summer days because of high air conditioning requirements, other electricity demand, and high transfers of power for economic reasons, all of which increase the need for reactive power. Operators address these challenges through long-term planning, day-ahead planning, and real-time adjustments to operating equipment. On August 14, for example, PJM implemented routine voltage management procedures developed for heavy load conditions. FE also began preparations early in the afternoon of August 14, requesting capacitors to be restored to service[2] and additional voltage support from generators.[3] Such actions were typical of many system operators that day as well as on other days with high electric demand. As the day progressed, operators across the region took additional actions, such as increasing plants' reactive power output, plant redispatch, transformer tap changes, and increased use of capacitors to respond to changing voltage conditions.

The power flow data for northern Ohio on August 14 just before the Harding-Chamberlin line tripped at 15:05 EDT (Figure 3.2) show that FE's load was approximately 12,080 MW. FE was importing about 2,575 MW, 21% of its total system needs, and generating the remainder. With this high level of imports and high air conditioning loads in the

Independent Power Producers and Reactive Power

Independent power producers (IPPs) are power plants that are not owned by utilities. They operate according to market opportunities and their contractual agreements with utilities, and may or may not be under the direct control of grid operators. An IPP's reactive power obligations are determined by the terms of its contractual interconnection agreement with the local transmission owner. Under routine conditions, some IPPs provide limited reactive power because they are not required or paid to produce it; they are only paid to produce active power. (Generation of reactive power by a generator can require scaling back generation of active power.) Some contracts, however, compensate IPPs for following a voltage schedule set by the system operator, which requires the IPP to vary its output of reactive power as system conditions change. Further, contracts typically require increased reactive power production from IPPs when it is requested by the control area operator during times of a system emergency. In some contracts, provisions call for the payment of opportunity costs to IPPs when they are called on for reactive power (i.e., they are paid the value of foregone active power production).

Thus, the suggestion that IPPs may have contributed to the difficulties of reliability management on August 14 because they don't provide reactive power is misplaced. What the IPP is required to produce is governed by contractual arrangements, which usually include provisions for contributions to reliability, particularly during system emergencies. More importantly, it is the responsibility of system planners and operators, not IPPs, to plan for reactive power requirements and make any short-term arrangements needed to ensure that adequate reactive power resources will be available.

metropolitan areas around the southern end of Lake Erie, FE's system reactive power needs rose further. Investigation team modeling indicates that at 15:00 EDT, with Eastlake 5 out of service, FE was a net importer of about 132 MVAr. A significant amount of power also was flowing through northern Ohio on its way to Michigan and Ontario (Figure 3.2). The net effect of this flow pattern and load composition was to depress voltages in northern Ohio.

Unanticipated Outages of Transmission and Generation on August 14

Three significant unplanned outages occurred in the Ohio area on August 14 prior to 15:05 EDT. Around noon, several Cinergy transmission lines in south-central Indiana tripped; at 13:31 EDT, FE's Eastlake 5 generating unit along the southwestern shore of Lake Erie tripped; at 14:02 EDT, a Dayton Power and Light (DPL) line, the Stuart-Atlanta 345-kV line in southern Ohio, tripped.

- Transmission lines on the Cinergy 345-, 230-, and 138-kV systems experienced a series of outages starting at 12:08 EDT and remained out of service during the entire blackout. The loss of these lines caused significant voltage and loading problems in the Cinergy area. Cinergy made generation changes, and MISO operators responded by implementing transmission load relief (TLR) procedures to control flows on the transmission system in south-central Indiana. System modeling by the investigation team (see details below, page 20) showed that the loss of these lines was *not* electrically related to subsequent events in northern Ohio that led to the blackout.
- The DPL Stuart-Atlanta 345-kV line, linking DPL to AEP and monitored by the PJM reliability coordinator, tripped at 14:02 EDT. This was the result of a tree contact, and the line remained out of service during the entire blackout. As explained below, system modeling by the investigation team has shown that this outage was not a cause of the subsequent events in northern Ohio that led to the blackout. However, since the line was not in MISO's footprint, MISO operators did not monitor the status of this line, and did not know that it had gone out of service. This led to a data mismatch that prevented MISO's state estimator (a key monitoring tool) from producing usable results later in the day at a time when system conditions in FE's control area were deteriorating (see details below, page 27).
- Eastlake Unit 5 is a 597-MW generating unit located just west of Cleveland near Lake Erie. It is a major source of reactive power support for the Cleveland area. It tripped at 13:31. The cause of the trip was that as the Eastlake 5 operator sought to increase the unit's reactive power

Power Flow Simulation of Pre-Cascade Conditions

The bulk power system has no memory. It does not matter if frequencies or voltage were unusual an hour, a day, or a month earlier. What matters for reliability are loadings on facilities, voltages, and system frequency at a given moment and the collective capability of these system components at that same moment to withstand a contingency without exceeding thermal, voltage, or stability limits.

Power system engineers use a technique called power flow simulation to reproduce known operating conditions at a specific time by calibrating an initial simulation to observed voltages and line flows. The calibrated simulation can then be used to answer a series of "what if" questions to determine whether the system was in a safe operating state at that time. The "what if" questions consist of systematically simulating outages by removing key elements (e.g., generators or transmission lines) one by one and reassessing the system each time to determine whether line or voltage limits would be exceeded. If a limit is exceeded, the system is not in a secure state. As described in Chapter 2, NERC operating policies require operators, upon finding that their system is not in a reliable state, to take immediate actions to restore the system to a reliable state as soon as possible and within a maximum of 30 minutes.

To analyze the evolution of the system on the afternoon of August 14, this process was followed to model several points in time, corresponding to key transmission line trips. For each point, three solutions were obtained: (1) conditions immediately before a facility tripped off; (2) conditions immediately after the trip; and (3) conditions created by any automatic actions taken following the trip.

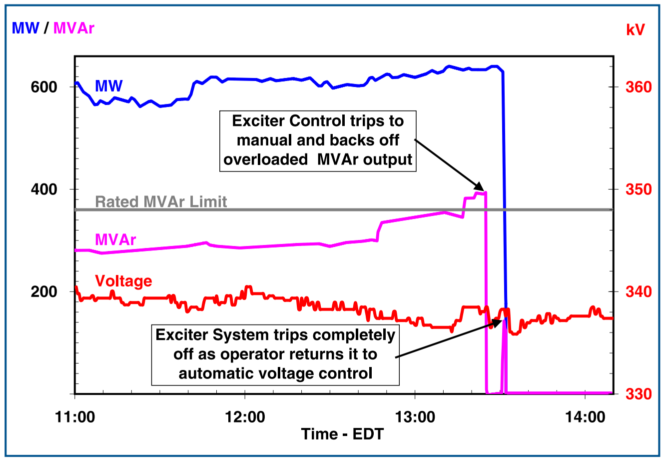
output (Figure 3.5), the unit's protection system detected a failure and tripped the unit off-line. The loss of the Eastlake 5 unit did not put the grid into an unreliable state—i.e., it was still able to withstand safely another contingency. However, the loss of the unit required FE to import additional power to make up for the loss of the unit's output (540 MW), made voltage management in northern Ohio more challenging, and gave FE operators less flexibility in operating their system (see details below, page 27).

Model-Based Analysis of the State of the Regional Power System at 15:05 EDT, Before the Loss of FE's Harding-Chamberlin 345-kV Line

As the first step in modeling the evolution of the August 14 blackout, the investigative team established a base case by creating a power flow simulation for the entire Eastern Interconnection and benchmarking it to recorded system conditions at 15:05 EDT on August 14. The team started with a projected summer 2003 power flow case developed in the spring of 2003 by the Regional Reliability Councils to establish guidelines for safe operations for the coming summer. The level of detail involved in this region-wide study far exceeds that normally considered by individual control areas and reliability coordinators. It consists of a detailed representation of more than 43,000 buses (points at which lines, transformers, and/or generators converge), 57,600 transmission lines, and all major generating stations across the northern U.S. and eastern Canada. The team then revised the summer power flow case to match recorded generation, demand, and power interchange levels among control areas at 15:05 EDT on August 14. The benchmarking consisted of matching the calculated voltages and line flows to recorded observations at more than 1,500 locations within the grid. Thousands of hours of effort were required to benchmark the model satisfactorily to observed conditions at 15:05 EDT.

Once the base case was benchmarked, the team ran a contingency analysis that considered more than 800 possible events as points of departure from the 15:05 EDT case. None of these contingencies resulted in a violation of a transmission line loading or bus voltage limit prior to the trip of FE's

Figure 3.5. MW and MVAr Output from Eastlake Unit 5 on August 14



Harding-Chamberlin 345-kV line. That is, according to these simulations, the system at 15:05 EDT was able to be operated safely following the occurrence of any of the tested contingencies. From an electrical standpoint, therefore, the Eastern Interconnection was then being operated within all established limits and in full compliance with NERC's operating policies. However, after loss of the Harding-Chamberlin 345-kV line, the system would have exceeded emergency ratings on several lines for two of the contingencies studied. In other words, it would no longer be operating in compliance with NERC operating policies.

Conclusion

Determining that the system was in a reliable operational state at 15:05 EDT is extremely significant for understanding the causes of the blackout. It means that none of the electrical conditions on the system before 15:05 EDT was a cause of the blackout. This eliminates high power flows to Canada, unusual system frequencies, low voltages earlier in the day or on prior days, and the unavailability of individual generators or transmission lines, either individually or in combination with one another, as direct, principal or sole causes of the blackout.

Endnotes

[1] DOE/NERC fact-finding meeting, September 2003, statement by Mr. Steve Morgan (FE), PR0890803, lines 5-23.

[2] Transmission operator at FE requested the restoration of the Avon Substation capacitor bank #2. Example at Channel 3, 13:33:40.

[3] From 13:13 through 13:28, reliability operator at FE called nine plant operators to request additional voltage support. Examples at Channel 16, 13:13:18, 13:15:49, 13:16:44, 13:20:44, 13:22:07, 13:23:24, 13:24:38, 13:26:04, 13:28:40.